part 1

# Virginia State Corporation Commission
# eFiling CASE Document Cover Sheet

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**Case Name** **(if known)** Application of Virginia Electric and Power Company in re: Virginia Electric and Power Company's Integrated Resource Plan filing

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August 11, 2017

**VIA ELECTRONIC FILING**

Mr. Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

**RE:** ***Application of Virginia Electric and Power Company in re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to § 56-597 et seq.***

**Case No. PUR-2017-00051**

Dear Mr. Peck:

Attached for filing in the above-referenced matter is the Direct Testimony and exhibits of Gregory Lander, which is being submitted on behalf of the Natural Resources Defense Council, Appalachian Voices, and the Chesapeake Climate Action Network (collectively, "Environmental Respondents"). This filing is being completed electronically, pursuant to the Commission's Electronic Document Filing system.

If you should have any questions regarding this filing, please contact me at (434) 977-4090.

Regards,

William C. Cleveland

William C. Cleveland

cc: Parties on Service List
Commission Staff

**COMMONWEALTH OF VIRGINIA**

**STATE CORPORATION COMMISSION**

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| APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY | ) | |
| | ) | Case No. PUR-2017-00051 |
| *In Reference: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.* | ) | |

**Summary of Direct Testimony of**

**Gregory M. Lander**

**On Behalf of**

**Environmental Respondents**

**August 11, 2017**

## <u>Summary of Testimony of Gregory M. Lander</u>

My name is Gregory M. Lander. I am head of Skipping Stone, Inc.'s Energy Logistics practice. My testimony focuses on the cost that Dominion Energy Virginia ratepayers will bear if the Atlantic Coast Pipeline is constructed. Contrary to a report by ICF International that the Company released in 2015, using data I obtained from the Company during this IRP process, I calculate that the Atlantic Coast Pipeline will increase costs for Dominion ratepayers between $1.61 and $2.36 billion.

In light of these unnecessary costs, I offer two proposals for how the Commission can shield Dominion ratepayers from these costs in the event that the pipeline is built.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

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**Direct Testimony of**

**Gregory M. Lander**

**On Behalf of**

**Environmental Respondents**

**August 11, 2017**

**Q. Please state your name and address.**

A. My name is Gregory M. Lander. My mailing address is 83 Pine Street, Suite 101, West Peabody, MA 01960, and my email address is glander@skippingstone.com.

**Q. What is the purpose of your testimony today?**

A. My testimony addresses two primary concerns. First, in discussing the proposed Atlantic Coast Pipeline (the "ACP"), the Company has publicly released a report from ICF International claiming that the ACP will save Company ratepayers money.[1] According to the ICF report, the ACP will provide access to natural gas located at the Dominion South Point pooling location, which will allegedly be lower cost than natural gas from either Henry Hub or Transco Zone 5. ICF further asserts that the price savings are so great that they more than offset the increased transportation costs associated with using the new ACP, thus producing a net customer savings.

**Q. In your analysis, does Dominion's 2017 Integrated Resource Plan ("IRP") support this conclusion?**

A. No, it does not. In my analysis, detailed below, using Dominion's own modeling numbers and assumptions from this year's IRP, the costs of transportation along the Atlantic Coast Pipeline will actually outweigh the reduced natural gas prices at Dominion South Point. As such, using Dominion's own 2017 IRP data, the ACP will actually ***<u>increase</u>*** customer costs between $1.61 and $2.36 billion.

**Q. What else does your testimony include?**

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[1] *The Economic Impacts of the Atlantic Coast Pipeline*, prepared for Dominion Transmission, Inc. by ICF International (Feb. 9, 2015) (the "ICF Report"), *available at* https://www.dominionenergy.com/library/domcom/pdfs/gas-transmission/atlantic-coast-pipeline/acp-icf-study.pdf, at 5 ("Between 2019 and 2038, ICF estimates a net annual average energy cost savings of over $377 million dollars - $243 million in Virginia, and $134 million in North Carolina. These benefits accrue to both natural gas and electric consumers and add to the construction and local tax benefits identified in other studies.").

A. If the Company does build the ACP, I offer two solutions the Virginia SCC could employ to shield Dominion ratepayers from these increased costs.

**Qualifications**

**Q. What is your educational and professional background?**

A. I graduated from Hampshire College in Amherst, MA, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, MA ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (Order Nos. 587 *et seq.*). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces. I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. ("Skipping Stone") acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's

Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone launched CapacityCenter.com, a pipeline capacity information service. In 2004, Skipping Stone was acquired by Commerce Energy Group, a national retail energy services provider. In 2005, I was appointed President of Skipping Stone, which operated as a wholly owned subsidiary of Commerce Energy Group. In 2008, I purchased substantially all of the assets of Skipping Stone and now operate essentially the same business as before the Commerce Energy transaction as Skipping Stone, LLC.

From 1984 to present, I have maintained a deep familiarity with the wide range of pipeline transportation issues; beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns; restructuring of the pipelines from merchants to transporters and thereafter, with respect to pipeline capacity issues beginning with the definitions of what constituted a pipeline capacity "right" for the purposes of formulating the newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50+ pipeline and storage mergers and acquisitions ("M&A") transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

**Q. Have you filed testimony in regulatory proceedings previously?**

A. I filed testimony in FERC proceedings including Docket No. RP01-486-000, addressing, among other things, the reasons why there was a shortfall of firm capacity on the El Paso Natural Gas ("EPNG") system in the years 2000-01. I filed testimony in Docket No. RP04-251-000, which was an EPNG proceeding regarding pathing and segmentation. In Docket No. RP08-426-000, (also an EPNG proceeding) I sponsored answering and supplemental answering testimony. I also filed testimony Docket No. RP10-1398 ("EPNG") when it went to the hearing in 2014 as the first fully litigated EPNG Rate case in more than three decades. I also filed testimony in Massachusetts DPU cases 13-157, 15-34, 15-48, 15-39 and Maine PSC case 2014-00071. All of the state regulatory cases involved state regulatory determinations with respect to Local Distribution Companies or electric LSEs entering into pipeline agreements for new capacity.

**Q. Are you submitting attachments along with your testimony?**

A. Yes. They are:

1. Exhibit Lander-1
2. Exhibit Lander-2
3. Exhibit Lander-3
4. ER 1-1
5. Attachment ER Set 1-1 (a)
6. ER 1-40
7. Attachments ER Set 1-40 (AV) (1)
8. ER 3-07
9. Attachment ER 3-07 (DEH)
10. ER 3-9
11. ER 4-10
12. ER 4-12
13. ER 4-13
14. ER 6-18

**Q. What issues will your testimony cover?**

A. I will cover what I believe is a contradiction between public statements adopted by the Company with respect to the "value" of the Atlantic Coast Pipeline ("ACP") and the Company's own projections used in the IRP as to the likely "value"—or rather net cost to ratepayers—of the ACP. In addition, I propose two mitigation measures that the Virginia SCC can adopt to shield ratepayers from what I calculate, using the Company's own projections, to be the net cost to ratepayers as a result of the Company's subscription to transportation service on the ACP.[2] I perform these calculations based upon a series of assumptions as to rates to be paid by VPSE to the ACP and assumptions used by the Company as to gas prices.

**Q. When you refer to the Company's public statements about the ACP's value, are you referring to this year's IRP?**

A. No. I am specifically referring to the February 9, 2015 ICF report prepared for Dominion Transmission Inc. ("DTI") that the Company made public at that time.

**Q. What did ICF conclude about the ACP in 2015?**

**A.** ICF concluded that the ACP would produce a net savings for Dominion customers.

**Q. On what did ICF base their calculations of potential savings?**

A. ICF presented savings as a result of lower gas prices into ACP as represented by prices at the supply pooling point known as Dominion South Point plus the cost of transportation on ACP versus regional gas prices in Transco Zone 5. Dominion South Point is the

[2] The Company states in its IRP that, "In August 2014, the Company executed a precedent agreement to secure firm transportation services on the ACP." 2017 IRP at 72. Technically, this is incorrect. Pursuant to an SCC-approved affiliates agreement, a Company subsidiary, Virginia Power Services Energy, Corp. ("VPSE") is the signatory on the precedent agreements. The Company, and thus its ratepayers, however, ultimately bear the cost of all precedent agreements that VPSE signs. *See Petition of Virginia Electric and Power Company - To revise its fuel factor pursuant to Va. Code § 56-249.6*, Case No. PUR-2017-00058, June 14, 2017 Hearing Tr.at 45:6-10.

pricing point in Appalachia that is accessible to DTI and the proposed ACP line. Transco Zone 5 is the segment of Transcontinental Gas Pipeline ("Transco") that runs from a point in North-Central South Carolina to the Virginia/Maryland border.[3] Historically, as presented in the ICF Report, prices of gas at Dominion South Point have been higher than prices a Transco Zone 5. This is about to change.

**Q. Does the Company's 2017 IRP reflect changes in the relationship between gas prices at Dominion South Point and gas prices at Transco Zone 5?**

A. Yes, these changes are captured in the Company's response to ER 4-10 and ER 4-12, which presents future projected pricing data (basis) provided to the Company for use in its IRP Modeling. I will get to this below.

**Q. Before you get to discussing how the pricing relationships between Dominion South Point and Transco Zone 5 will change, please explain how prices for Dominion South Point and Transco Zone 5 are calculated for the purposes of your testimony.**

A: Sure. Prices of Dominion South Point determine prices for gas into the DTI pipeline, which delivers gas to the Local Distribution Companies ("LDCs") that serve 4 of the 18 plants identified by the Company in Attachment ER 3-07 (DEH). To estimate the cost of gas used to generate electricity at plants served directly (or indirectly) by DTI, one needs to calculate the "delivered" cost of gas, which is the sum of the price of gas at Dominion South Point, plus variable transportation costs through DTI, plus variable transportation costs through the LDCs (both costs inclusive of fuel used to move the gas plus an additional cost associated with lost and unaccounted for gas).

[3] There are six distinct Transco Zones and most have at least one liquid natural gas pricing location associated with the Zone.

**Q: What is the cost of fuel?**

A: The "cost of fuel" or fuel rate on DTI is roughly 2%; which means that DTI delivers approximately 98% of the gas they receive. If gas costs $2.00 per Dth, this fuel rate would add approximately another $0.04 per Dth to the delivered price/cost of gas.

**Q: Is the "delivered" price of gas the same as the All-in Cost of gas?**

A: No. To calculate an All-In Cost of Gas, one would also take into account the amounts paid to reserve capacity on the pipeline (and the LDC if such reservation costs are paid) and divide those costs by the units transported to arrive at a per unit transportation reservation cost, which would be added to the variable costs (gas and capacity usage costs). Typically the 100% load factor equivalent of the DTI Firm Transportation charge is about $0.14 per Dth.

**Q: Why is the load factor important?**

A: 100% load factor equivalent assumes the contract holder uses all of their capacity every day. In contrast, if a contract holder uses only 80% of their reserved capacity (meaning they are an 80% load factor customer), the effective cost for the units of DTI capacity used becomes $0.175 per unit used (*i.e.*, $0.14 divided by 0.8 = $0.175).

**Q: How do these calculations about the cost of gas from Dominion South Point compare to the calculations about the cost of gas in Transco Zone 5?**

A. In contrast to the above rough calculations of Dominion South Point (into the pipe prices) moved forward to market (*i.e.*, where the gas is burned), the prices in Transco Zone 5 are prices that are already reflective of prices "out of the pipe" (*i.e.*, prices at the market location as opposed to prices at the supply location). The reported prices for Transco Zone 5 determine prices for gas delivered within Transco's Zone 5 (again, the segment of

Transco pipeline that runs from a point in North-Central South Carolina to the Virginia/Maryland border). Transco is the pipeline which delivers gas to the one (1) plant served directly by Transco and the five (5) plants served by LDCs (6 plants in total of the 18 plants) as identified by the Company in Attachment ER 3-07 (DEH).

Seven (7) plants are served either directly by (or by LDCs served by) Columbia Gas Transmission ("TCO") and one (1) plant is served by Cove Point LNG's pipeline. The 14 of 18 plants not served by LDCs served by DTI are all plants whose gas supplies are driven by Transco Zone 5 pricing (*See* ER 1-1(a) and ER 4-13) – that is, gas prices at the market locations where gas is delivered for gas-fired generators of the Company.

| Power Station[4] | Pipeline / LDC |
|---|---|
| Bellemeade | City of Richmond |
| TCO - Chesterfield | Columbia Gas of Virginia |
| Gravel Neck | Columbia Gas of Virginia |
| Gordonsville | Columbia Gas of Virginia |
| Eliz River | Columbia Gas of Virginia |
| Remington | Columbia Gas of Virginia |
| Altavista | Columbia Gas of Virginia |
| Hopewell | Columbia Gas of Virginia |
| Bear Garden | Columbia Gas of Virginia |
| Bremo | Columbia Gas of Virginia |
| Warren County | Columbia Gas Transmission |
| Possum Point | Cove Point Pipeline |
| Rosemary | Piedmont Natural Gas |
| Brunswick County | Transcontinental Gas Pipeline Company, LLC |
| Darbytown | Virginia Natural Gas |
| DTI-Chesterfield | Virginia Natural Gas |
| Yorktown | Virginia Natural Gas |
| Ladysmith | Virginia Natural Gas |

[4] *See* Attachment ER 3-07 (DEH).

**Q. Do you take issue with the statement by the Company in ER 1-1(a) or ER 4-13 that the Delivered Price at Transco Zone 5 was assumed to apply to all gas fired generating units within the DOM Zone?**

A. No. It is a very reasonable assumption as to the 14 of 18 plants, given the dynamics of the gas market and the locations of the Company plants.

**Q. Do purchases of gas for the plants where Transco Zone 5 pricing is assumed also have transportation costs associated with them?**

A. For many of the purchases yes, for others no. When gas is bought from sellers on a "delivered to the plant" (or LDC) basis, the price of the gas includes the costs to the seller of the transportation. When capacity held by VPSE is used, then yes, transportation costs, including reservation charges are additive.

**Q. Would it be fair to say that including those costs of transportation for the plants served by Transco in Zone 5 would yield prices roughly the same as those prices charged by sellers making delivery point sales in Zone 5?**

A. Transco's rate design is much more complicated than DTI's and getting precise figures for receipt point purchase prices and then adding transportation costs (including load factor equivalents for reservation charges) would probably yield All-In Cost of Gas prices close enough to Zone 5 prices that relying on Transco Zone 5 prices is a very good proxy for the All-In Cost of Gas for the purposes of this testimony.

**Q. Can you now relate this discussion on All-in Cost of Gas to the ICF report as to the value of ACP?**

A. Yes. In the ICF Report, ICF estimates two pertinent "values" to the ACP line. First, it states that the ACP will provide access to lower-cost gas at Dominion South Point and that the cost savings in gas more than offset the increased transportation costs associated with using the new ACP. The ICF Report states:

> As seen in Exhibit 8, ICF estimates that, as compared to purchasing gas supplies delivered into the market, ACP gas buyers could save $1.61/MMBtu on average by transporting Appalachian Basin gas on ACP – far exceeding the proposed transportation rate on the pipeline. The cost savings enabled by the ACP occur early in the life of the project and grow steadily over time.[5]

Second, it presents two views of Transco Zone 5 prices; one with ACP and one without ACP. See ICF Exhibit 8 below:

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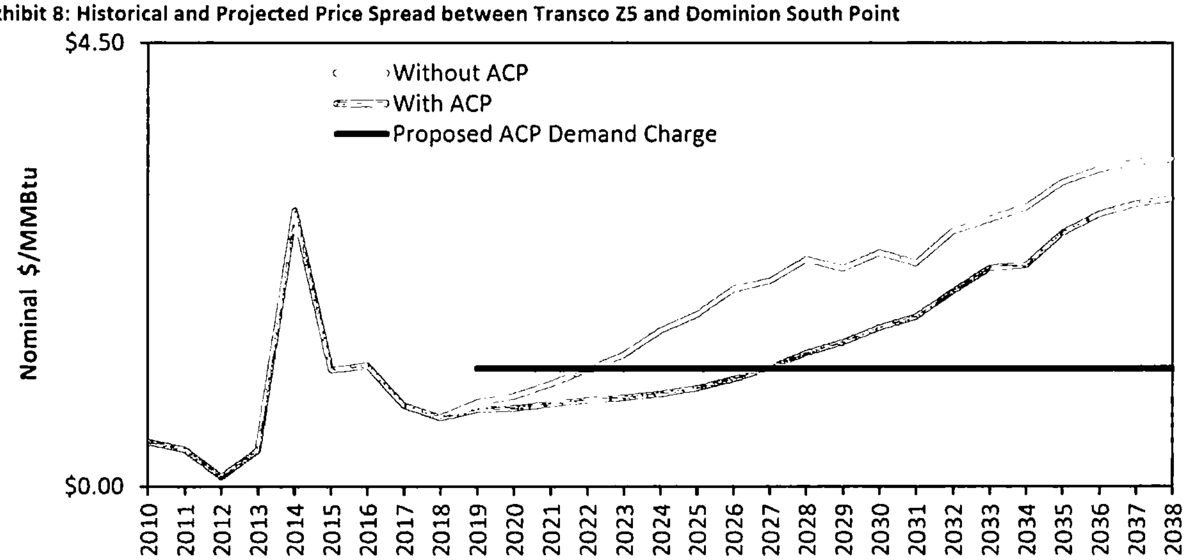
**Exhibit 8: Historical and Projected Price Spread between Transco Z5 and Dominion South Point**




Source: ICF

This presentation provides the ICF view of an historic and future "price spread" between Dominion South Point and Transco Zone 5.

[5] ICF Report at 9.

**Q. What is a "price spread"?**

A. A price spread is a metric used to determine the relative difference between prices at two different liquid gas pricing locations (*i.e.*, which pricing location is the lower or higher priced depending on viewpoint).

**Q. How do you calculate a price spread?**

A. All price spreads begin with a comparison of gas prices in a specific location against gas prices at the Henry Hub, *i.e.* the "basis" for that location. In this instance, I would, and ICF did, first calculate the price differential (basis) between Henry Hub and Dominion South Point. Then one would calculate the price differential (again basis) between Henry Hub and Transco Zone 5. Price spreads are then calculated by taking the difference between the "basis" of one location ("Dominion South Point") and comparing it to (*i.e.*, subtracting it from) the "basis" of the other location. If the difference (basis) between Henry Hub and Dominion South Point (Location 1) is negative $1.61, and the price differential between Henry Hub and Transco Zone 5 (Location 2) is positive $1.00 the price spread is $2.61 between Dominion South Point and Transco Zone 5 (*i.e.*, $1.00 minus ($1.61) = $2.61).

**Q. What does a price spread of $2.61 between Dominion South Point and Transco Zone 5 mean?**

A. This implies that as long as the All-In Cost to transport gas from Dominion South Point to Location 2 is less than the Price Spread, that there would be savings. Said another way, transportation costs (all of them) from Dominion South Point to Location 2 would have to be less than the Price Spread between Dominion South Point and Location 2 (*i.e.*, Transco Zone 5) for there to be a savings associated with buying Dominion South Point gas and transporting it to Location 2 on the ACP instead of just buying the gas at Location 2 – where the gas-fired generators are located.

**Q. You said that the pricing relationships between Dominion South Point and Transco Zone 5 will change, please discuss this.**

A. Not only is it my view that the pricing relationship between Dominion South Point and Transco Zone 5 will change from the historic relationship, it is also the view of the Company in this IRP.

**Q. Please explain further.**

A. In response to ER 4-10, the Company provided 200 iterations of future basis for each month from January 2017 through December 2042.[6] In response to ER 4-12, the Company identified Iteration 123 as the "Medium Expected Levelized Average Cost" for the No CPP Plan (Plan A). I loaded the entire data series (all 200 iterations) from Attachment ER 4-10 (AV) into a database and then did two extractions from that database. One extraction was all months for all years of Iteration 123. The other extraction was an average of all 200 Iterations for all months of all years. In each extraction, I extracted Dominion South Point and the Transco Zone 5 Basis figures.

**Q. Why did you pick both Iteration 123 and the average of all 200 Iterations?**

A. I picked Iteration 123 because that was the medium price expectation picked by the Company under Plan A No CPP. I then picked an average of all 200 Iterations because from a modeling and analysis point of view picking the average of all Iterations provides another view as to the totality of potential expected outcomes, and it should provide a

[6] Attachment ER Set 4-10 (AV). Due to the size of the spreadsheet, it is not attached as an exhibit to this testimony but is available upon request.

band of reasonableness with which to evaluate the picking of a single Iteration as representative of Medium Expectations.

**Q. What did you find after doing these two extractions?**

A. I found that over the 20 years of the initial term of VPSE's contract with ACP that the average basis for Dominion South Point, as used in the Company's 2017 IRP Model (*i.e.*, Iteration 123), was ($0.74) (*i.e.*, $0.74 less than Henry Hub). Likewise, over the same period, I found that the Transco Zone 5 basis, as used in the Company's 2017 IRP Model (again Iteration 123), was ($0.28) (*i.e.*, $0.28 less than Henry Hub). This yields a "Price Spread" of only $0.46 (forty six cents) (*i.e.*, ($0.28) minus ($0.74) = $0.46).

**Q. How does this compare to ICF's 2015 estimates of the Dominion South Point / Transco Zone 5 price spread?**

A. This is a far cry from not only the ICF figures for Dominion South Point as being ($1.61) to the Hub (*i.e.*, supposedly "paying" for the cost of ACP) but also far from the "price spread" in ICF's Exhibit 8, which appears to show that the price spread with ACP begins at a value that is slightly less that what I estimated from the Exhibit was about $1.40 (which appears to be the "Proposed ACP Demand (*i.e.*, reservation) Charge") rising to an approximately $3.00 Price spread by 2038.

**Q. What did you do next?**

A. Next, I took these two extractions and made a model (Exhibit Lander-3) which calculated the Price Spread (*i.e.*, Value of ACP) averaging the monthly basis for each of Dominion South Point and Transco Zone 5 by year and deriving the Price Spread (ACP Value) by year for each of the 20 years of the VPSE-ACP contract.

**Q. What did you do after that?**

A. I then took my estimates of the 100% load factor cost to VPSE of the ACP contract and subtracted them from the Value by year of the Price Spread to identify Net Cost of ACP to ratepayers.

**Q. What estimates of ACP 100% load factor costs did you use?**

A. I used two different 100% Load Factor costs. One was based upon the 100% Load Factor rate published by ACP in its Exhibit P to the FERC application filed by ACP. The other was a discount to that rate which I have found to be a typical discount accorded subscribing Foundation Shippers (of which VPSE is one).

**Q. What is that typical discount, and what 100% Load Factor rate would result?**

A. In my experience a very typical discount to Foundation Shippers is 20% off of the Exhibit P rate. In this case, with an approximately $1.75 per Dth 100% load factor rate, I would estimate that the Foundation Shipper rate would be $1.40 per Dth at 100% Load Factor.

**Q. Is it customary to use the 100% load factor equivalent of the combined reservation and usage rates to make an All-in Cost of Gas estimation?**

A. It depends on the expected load factor that the shipper will make use of the totality of capacity in their portfolio, and what kind of shipper they are.

**Q. Please explain.**

A. Well, a producer, which has a substantially level flow from their wells every day, can expect to see their cost of transportation, which determines the All-In Cost of Gas at their sales point(s) to be very close to 100% usage of capacity and thus the 100% load factor rate is reasonable. On the other hand, if the shipper is a shipper with seasonal or weather-sensitive load, like a generator with a portfolio of assets to serve weather-sensitive customers or an LDC, their actual realized load factor may be very much lower, making the effective All-In Cost of Gas (with the lower load factor) much higher. For instance, for a company with a reservation rate of $1.39 that operates at 80% load factor, the effective transportation rate per unit actually used becomes $1.7375; an increase of $0.3475 per Dth per day.

**Q. So, are you possibly understating the "cost" of ACP by using the 100% load factor equivalent?**

A. I am being somewhat generous as to the probable actual cost–in-use of the ACP line. Nevertheless, I used the 100% load factor equivalent, because it appears that is what ICF used in its report. Were I to assume an 80% load factor usage by the Company of its capacity portfolio, then the net cost of the ACP portion of its portfolio would be commensurately higher and the net cost to ratepayers, in turn, would be higher as well.

**Q. Getting back to the Price Spread / Net Cost of ACP to the Company Ratepayers model, did you make any other assumptions?**

A. Yes. I also assumed that every five years ACP would have a rate case which would lower return to account for depreciation. In this case I estimated that rates would decline about 10% every five years. I did this because of two likely reasons. One, a pipeline may be responding to its customers' desires to re-calibrate rates to take account of cost changes (especially return as a function of depreciation and Accumulated Deferred Income Taxes which also reduces rate base) and would do so by filing a rate case under Section 4 of the Natural Gas Act. Two, FERC has what are known as Natural Gas Act Section 5 rights to call a pipeline in for a rate case to reduce its rates, to the extent FERC can prove the pipeline is over-earning. While there is not a lot of experience as yet with the newest greenfields pipelines, as to periodic rate declines, historically, this had been the case, so it's not an unreasonable assumption to make here. That said, if the periodic, every five years or so, rate case and commensurate reductions do not occur for the ACP, then the net cost to ratepayers over time would be significantly higher than I have assumed in my modeling as to the net cost of ACP to ratepayers.

**Q. Does this assumption make ACP more "valuable" as rates go down?**

A. To some extent yes. However, my calculations, even with ACP rates declining, show there is never a net benefit to the Company ratepayers. In fact based upon the Company basis projections used in the Company's 2017 IRP, there is a net cost to the Company ratepayers throughout the term of the VPSE-ACP contract. This net cost arises from the precipitous decline in basis (under both the Iteration 123 and under the average of all 200 iterations) for both Dominion South Point and Transco Zone 5, which together drop the "Price Spread" or "Value" of ACP precipitously compared to what ICF posited. In addition, if the VPSE contract (which was not made available by the Company, even though it was requested) is a negotiated, fixed price, contract for the duration of the initial term, the Company customers would not see the benefit of lower rates coming out of any rate case.

**Q. Based upon these calculations what did your model present as the net cost under the four cases you ran, that is, Case 1: Iteration 123 with ACP initial rates of $1.75 declining with periodic rate cases, Case 2: Iteration 123 with ACP initial rates of $1.40 also declining with periodic rate cases; Case 3: Average of All 200 Iterations with ACP initial rates of $1.75 (also declining) and Case 4: Average of all 200 Iterations with ACP initial rates of $1.40 (also declining)?**

A. The net costs over 20 years are set forth below:

| Case | Net Cost to the Company Ratepayers |
|---|---|
| Case 1: Iteration 123 with ACP initial rates of $1.75, declining with periodic rate cases | $2,287,635,333 or ~$2.29 Billion |
| Case 2: Iteration 123 with ACP initial rates of $1.40, also declining with periodic rate cases | $1,626,686,958 or ~ $1.63 Billion |
| Case 3: Average of All 200 Iterations with ACP initial rates of $1.75 (also declining) | $2,319,970,794 or ~ 2.31 Billion |
| Case 4: Average of all 200 Iterations with ACP initial rates of $1.40 (also declining) | $1,660,972,419 or ~ $1.66 Billion |

(*See* Exhibit Lander-3 for derivations)

**Q. So, using the Company's 2017 IRP data, does it appear to you that the Company ratepayers do not see net savings flowing from the VPSE contract with ACP?**

A. Yes, but not only that, it may be even worse than presented above because even if all the gas is used in the most efficient Combined Cycle Turbines with heat rates approaching 6,500 Btu/Kw or 6.5 Dth/MWH, the actual cost for electricity is higher because only 65% or so of the energy in gas is converted to electricity under the most favorable of conditions. Under this set of parameters, the costs translated into electric costs would be between $2.5 Billion and $3.5 Billion. While this efficiency factor would apply to gas plants attached to any pipeline, the Company has embarked on replacing its coal-fired units with gas fired units, which according to the ICF Report (which also posits nuclear unit retirement) leads to an increase in gas demand in the future.

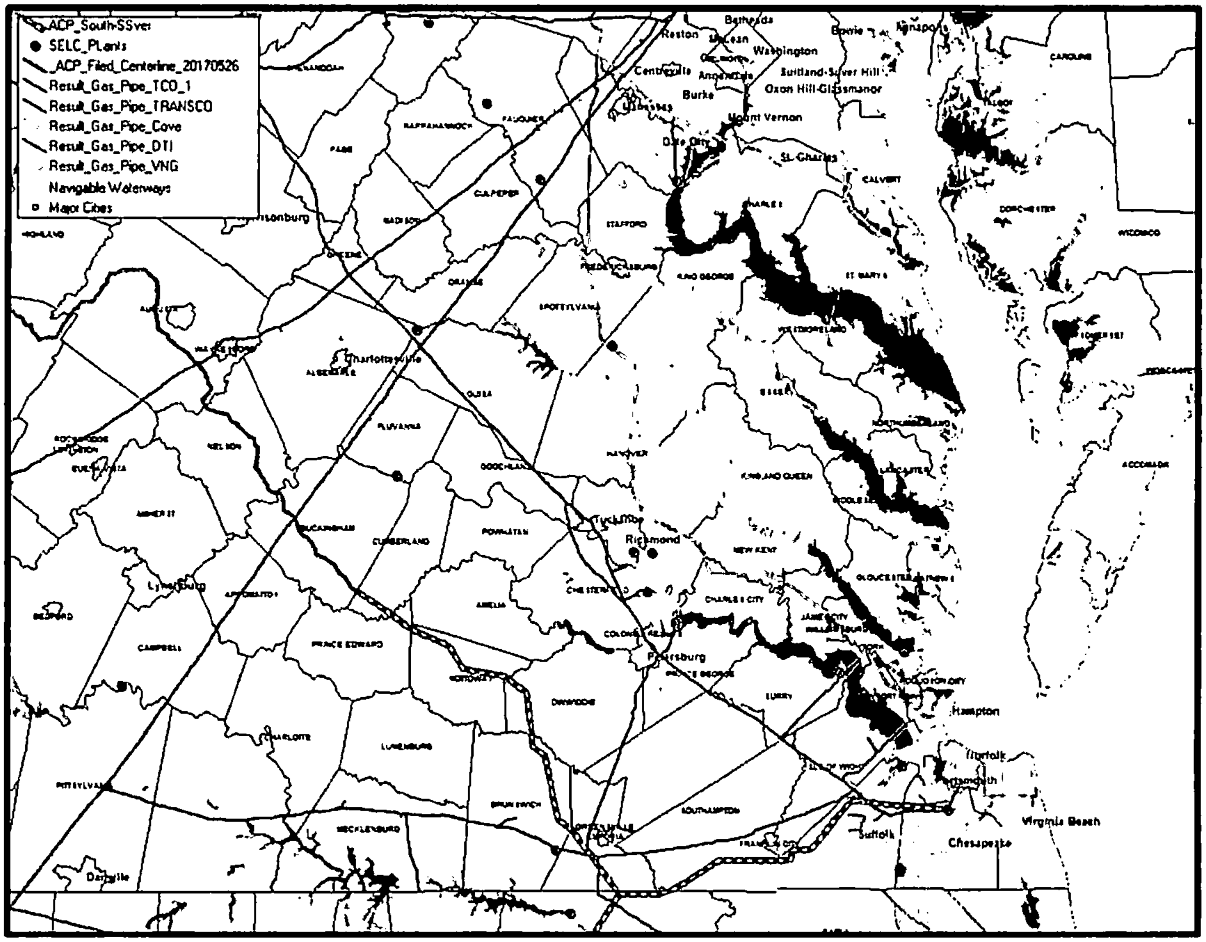
**Q. Wouldn't the ACP have other benefits to the Company ratepayers?**

A. First of all, the ACP will not directly connect to any current natural gas power plant, nor will it directly connect to any future natural gas power plant identified in the 2017 IRP. This includes the Greensville Plant. According to the Company's Response to ER 3-9, "[t]he Company's Greensville County Power Station will receive firm capacity from the Transcontinental Gas Pipe Line, and will have access to the Atlantic Coast Pipeline." Notably, having "access" is not the same as being "directly connected".

**Q. What does this mean?**

A. This means that all the Company plants will still have to get their gas from the last pipeline in the chain. The ACP may deliver to Transco in Zone 5, but that only means that the Company will still rely on Transco to get their gas to their generating stations. Skipping Stone has provided a map Exhibit Lander-1, upon which it has located both the Company power plants listed in the Company Response ER 3-7 as well as the pipelines in the same geographic regions. In addition, in Exhibit Lander–2, Skipping Stone has provided a column in addition to those provided by the Company in Response ER 3-7 that provide the approximate "as the crow flies" mileage from the nearest extent of the ACP line to each such plant. Fifteen of the plants are situated more than 20 miles (more than approximately $70-$80 Million dollars' worth of pipeline cost away) from the ACP.

The three plants that are within 20 miles from ACP lie between one and approximately six miles from the nearest ACP route, again "as the crow flies".




Please note that the rendering of the ACP line was done by Skipping Stone from an available ACP GIS layer to the border between Buckingham and Cumberland Counties Virginia and from an available ACP map of the balance of the Virginia extent of ACP as Skipping Stone did not have access to the actual GIS layer for the entire ACP route.

Q. **Does the fact that much of the gas on ACP would be delivered to Transco in Zone 5 account for the Transco Zone 5 basis being so much closer to the Henry Hub in the future than it is today, and was during the historic period used by ICF in their Report?**

A. Yes. The ACP will greatly increase supply available in Transco Zone 5 and, as a result, will have a large depressing effect on Transco Zone 5 basis (which drives prices). Moreover, even without the ACP, at least three other current projects will lower prices in Transco Zone 5: (1) Atlantic Sunrise, (2) the general reversal of Transco from Leidy to the Southeast, and (3) the potential Mountain Valley Pipeline. Each of these three will result in a vast increase in Appalachian-sourced supply being available in and to Transco Zone 5. Furthermore, it appears this likely effect is captured in the Company's Risk assessment in the 2017 IRP.

Q. **Would there be a mechanism that you could describe that would shield the Company ratepayers from the projected effect of this net cost of ACP on gas used to generate electricity?**

A. There are two that might achieve such mitigation.

Q. **Please describe the first.**

A. First, a little background is needed. Under the arrangement between VPSE, Virginia Power Energy Marketing ("VPEM") and the Company, titled the Affiliate Fuel Service Agreement and what I will term the Fuel Management Agreement, VPSE contracts for capacity and gas (including from VPEM). VPEM is a wholesale electricity and wholesale gas merchant. This means they make sales to others aside from VPSE. In addition, VPEM is the agent appointed to administer much of the pipeline capacity held by VPSE.

In fact, as of January 2016[7], VPSE held (and still holds) 1,026,919 Dth/d (1.026 Bcfd) of transportation capacity on interstate pipelines. In addition, VPSE also held (and still holds) 3 Bcf of storage capacity[8]. Of the transport capacity, all but 105,000 Dthd (~10%) can directly serve or has in path capacity rights able to serve the Company power plants. With respect to the approximately 1 Bcfd of transport capacity and the 3 Bcf of storage capacity, VPEM is VPSE's agent for all 3 Bcf of the storage capacity and 0.604 Bcfd of the VPSE transport capacity[9]. This means that under the Fuel Management Agreement, VPEM controls nearly 60% (58.8%) of this 1 Bcfd of transport capacity by means of its Agency status. In addition to the greater than 0.6 Bcfd of VPSE capacity VPEM controls; VPEM has another 0.22 Bcfd of capacity in its own name which it enables it to serve plants in the Northeast and to also fill the VPSE storage it controls[10].

**Q. Go on.**

A. Even though VPEM explicitly controls all VPSE capacity, except the Transco capacity, under the operation of the Fuel Management Agreement, VPEM can effectively control even that Transco capacity. With respect to all of VPSE's capacity, whether VPEM is explicitly in control or not, FERC rules with respect to "shipper must have title" mean that while VPSE is the shipper under the transport agreements, VPEM can get the benefit of these agreements through a series of "Buy-Sell" arrangements with VPSE. Under such arrangements, VPEM would buy gas at receipt points into Transco, then sell that same gas to VPSE before the gas goes into the Transco line, then VPSE transports gas it now

[7] And continuing through Jan of 2017.
[8] This 3 Bcf of storage capacity comes with 42,500 Dthd of withdrawal capacity able to feed DTI and Transco transport agreements.
[9] This is directly evidenced by the designation of VPEM as Agent in the filings by the interstate pipelines of their Index of Customers' listings.
[10] This is in addition to using DTI to fill the DTI storage.

holds the title for to the delivery point(s) under the Transco Agreement(s) then sells this gas at the delivery point(s) back to VPEM which then can either use the gas for VPEM generation or sell the gas to other downstream party(ies) at the delivery point(s). Just this sort of arrangement is explicitly contemplated by VPSE/VPEM/DVP as set forth in Attachment B of DVP's "Transaction Summary – Affiliate Transactions" as filed with the VSCC.

**Q. Please continue.**

A. The significance of this arrangement is that it would enable the Virginia SCC to require that VPEM/VPSE only transact with the Company at prices (inclusive of transportation to the Transco Zone 5 delivery points to the Company) that are equal to the lower of market or cost, and most significantly, fix the metric for "market", as the Company has done in the IRP, namely at the published Transco Zone 5 price on the day of the sale. And moreover, it would permit the Company ratepayers to not be burdened by capacity held by VPSE and controlled (or controllable by VPEM) which capacity is not utilized to generate electricity for the Company ratepayers. In short, the Virginia SCC should impose two requirements on the Company. First, it should require the Company to pay VPSE or VPEM for gas at "the lower of market or cost" through any capacity it holds or controls. Second, the SCC should not allow the Company to pay VPSE for any capacity that VPSE holds which is not directly utilized to generate electricity at the Company's plants. Effectively, this means that VPSE/VPEM would recover fixed reservation costs only to the extent the All-In Cost of Gas at the point(s) where the gas leaves the interstate market (whether it be via ACP or other routes) did not exceed the Transco Zone 5 Price.

**Q. Can you please explain your logic here?**

A. Certainly. In essence, if you look at the totality of the 2017 IRP, the Fuel Management Agreement, and the inclusion in the Company model of the costs of the ACP[11], the Dominion family of companies[12] (which is a mixture of federally regulated, state regulated and unregulated entities) have made a bet, backed by Virginia electric ratepayers, that having the ACP capacity is and will be better than just buying gas at Transco Zone 5 prices.

My recommendation is that the Virginia SCC should protect Virginia ratepayers with respect to this bet. They could do this by ensuring that the only costs Virginia ratepayers will bear are those costs that, on an All-In Cost of Gas basis, do not exceed what Virginia ratepayers would pay the Company if their gas for generation of electricity was purchased at Transco Zone 5 prices. In this way, the Virginia SCC gives the Dominion family the latitude to make investments and arrangements with regulated and unregulated affiliates and non-affiliates alike but requires that the Dominion family bear the risks of those investments and arrangements, not Virginia ratepayers.

**Q. You mention all these regulated and unregulated affiliates. Are you suggesting inappropriate behavior?**

A. No, that's not the point of my testimony. What I am suggesting is that, bottom line, it's about the tension between what is best for ratepayers and what is best for shareholders and how to assure that this tension and the possibility for erring on the side of

[11] *See* ER 6-18(a) where DOM includes "[T]he expected gas firm transportation service costs for the ACP pipeline . . . in row 9 (Virginia jurisdictional cost) of the sheet "1 _Fuel Backup" starting in the 2018/ 19 fuel year.").
[12] Dominion Resources, DTI, DOM VA, VPSE, and VPEM.

shareholders can and should be mitigated. One way to mitigate that tension is to protect Virginia ratepayers through this first possible mechanism I suggest.

Keep in mind, that under the Fuel Management Agreement, while the Company has appointed VPSE as its exclusive Fuel Manager, and VPEM manages both the VPSE capacity and sales to VPSE of gas, VPEM is not exclusive to VPSE (or the Company), and VPEM can use the capacity it holds or controls to make other sales as it sees fit. Given that fact, the Company (and its ratepayers) should not be on the hook to pay for any reserved capacity the Company does not directly get the beneficial use of (*i.e.,* directly benefits by means of daily delivered quantities); and when they do get the beneficial use of that capacity and the Fuel Management Agreement arrangements; that they should be protected. As mentioned above, the way to do this is for the Virginia SCC to require that the Company keep track of all Transco Zone 5 prices by day and pay to VPSE for gas the Company gets from VPSE that price (*i.e.*, the market price) every such day; and ***<u>not that "market price" plus fixed reservation costs</u>***. This mechanism, if adopted by the Virginia SCC would shift the risk of reserved capacity (which reserved capacity may or may not result in lower prices, as the Dominion family has asserted), off of the Company (and its ratepayers) and on to VPEM/VPSE and the rest of the Dominion family where it belongs.

**Q. You said there were two mitigation mechanisms. What is the other?**

A. The other mitigation mechanism would, with respect to the benchmarking against Transco Zone 5 Prices, operate similarly. The difference would be that the Virginia SCC would reduce the flow through to ratepayers of the difference between actual All-In Cost of Gas and what the cost of gas would have been based upon the Transco Zone 5 prices by the amount of return paid to ACP in rates paid by VPSE through rates until the Company ratepayers were kept whole on any difference in fuel costs.

**Q. How would the Virginia SCC know what the return component of the rates paid to ACP would be?**

A. If VPSE is paying the rates presented in Exhibit P of the ACP application, then approximately 75% of the ACP initial rate is made up of return. So, 75% of the amount paid by VPSE, would be the pot of dollars from which the "make whole" funds would be comprised. Then, once ratepayers were kept whole, the balance would no longer be credited to ratepayer fuel costs.

**Q. What if VPSE is paying a lower rate, as a Foundation Shipper, as you discussed above?**

A. In that event, I would have the return component of the ACP rate reduced by the difference between the dollars paid through the rate actually paid by VPSE to ACP and what the return component would have been at the Exhibit P rates. In short, the difference in dollars is taken "off the top" of the total return dollars that would be paid under the Exhibit P rates.

**Q. Why do you take the difference in dollars paid under the two rates "off the top"?**

A. Because, when a pipeline gives a discount, the effect on them is to reduce their return, assuming all other costs represent out-of-pocket cash costs or non-cash costs like depreciation.

**Q. Have you modeled a pro forma pot of dollars that would result from this type of mechanism?**

A. Yes. I introduced this concept into the model I developed showing the net cost of ACP (owing to the projected Price Spread) that I discussed above.

**Q. What was the result?**

A. In all four cases (the same as those discussed above) the modeled return exceeded the net cost of ACP by between $151 Million and $183 Million; meaning that the pot of dollars over the 20 Years of the contract associated with this modeled set of returns was sufficient to mitigate the modeled net cost to ratepayers and still provide the Dominion family with between $151 Million and $183 Million of profit.

**Q. Does that conclude your testimony?**

A. Yes.

# Lander

# Exhibits 1-3

## Exhibit ER-1

# Regional Pipelines and DOM VA Electric Generation Facilities

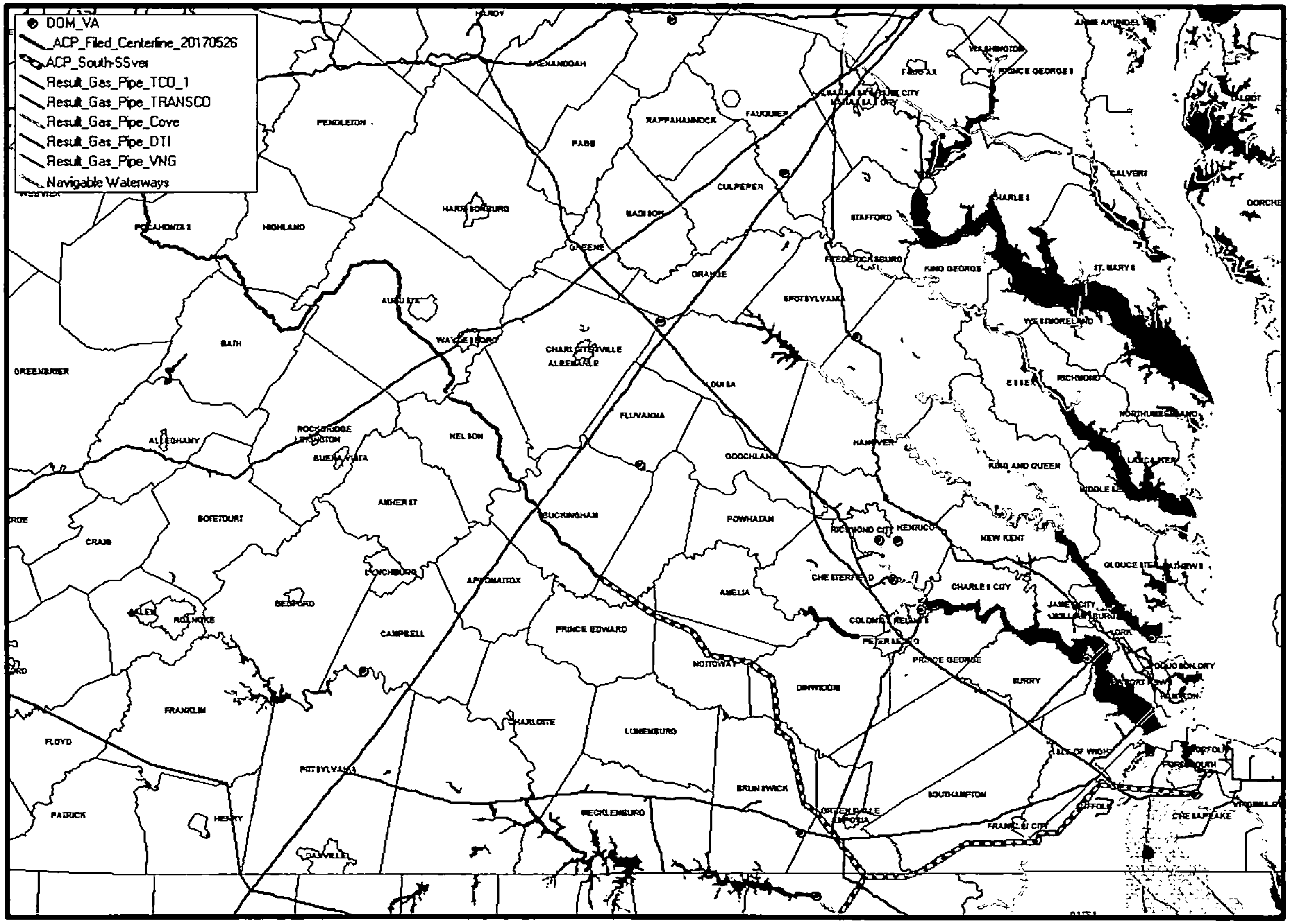



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Exhibit Lander-2

Miles to ACP From DOM VA Natural Gas-Fired Power Plants

# Attachment ER Set 3-7 (DEH) with Skipping Stone added Columns A, F, G & H

| A<br>Count | B<br>Power Station | C<br>Pipeline / LDC | D<br>Upstream Pipeline Delivery Point | E<br>Delivery Point | F<br>County | G<br>State | H<br>Miles to ACP |
|---|---|---|---|---|---|---|---|
| 1 | Possum Point | Cove Point Pipeline | N/A | Possum Point | Prince William | VA | 100+ |
| 2 | Yorktown | Virginia Natural Gas | DTI Quantico/VNG | Yorktown | York | VA | 30+ |
| 3 | TCO - Chesterfield | Columbia Gas of Virginia | TCO Meter #831082 | Chesterfield | Chesterfield | VA | 31+ |
| 4 | Gravel Neck | Columbia Gas of Virginia | TCO Meter #831081 | Gravel Neck | Surry | VA | 25+ |
| 5 | Bellemeade | City of Richmond | TCO Meter #837059 | Bellemeade | Richmond City | VA | 35+ |
| 6 | Gordonsville | Columbia Gas of Virginia | TCO Meter #833866 | Gordonsville | Louisa | VA | 40+ |
| 7 | Eliz River | Columbia Gas of Virginia | TCO Meter #833469 | Elizabeth River | Chesapeake | VA | ~1 |
| 8 | Darbytown | Virginia Natural Gas | DTI Quantico/VNG | Mechanicsville | Henrico | VA | 37+ |
| 9 | DTI-Chesterfield | Virginia Natural Gas | DTI Quantico/VNG | Mechanicsville | Chesterfield | VA | 31+ |
| 10 | Ladysmith | Virginia Natural Gas | DTI Quantico/VNG | Ladysmith | Spotsylvania | VA | 68+ |
| 11 | Remington | Columbia Gas of Virginia | Transco Remington/CGV | Remington | Fauquier | VA | 78+ |
| 12 | Altavista | Columbia Gas of Virginia | Transco Lynchburg/CGV | Altavista | Campbell | VA | 47+ |
| 13 | Hopewell | Columbia Gas of Virginia | TCO Market Area 1-33/CGV | Hopewell | Hopewell | VA | 32+ |
| 14 | Rosemary | Piedmont Natural Gas | Transco Panda Energy Meter #7319 | Rosemary | Halifax | NC | 5+ |
| 15 | Bear Garden | Columbia Gas of Virginia | Transco Bear Garden/CGV | Bear Garden | Buckingham | VA | 21+ |
| 16 | Bremo | Columbia Gas of Virginia | Transco Bear Garden/CGV | Bremo | Fluvanna | VA | 21+ |
| 17 | Warren County | Columbia Gas Transmission | N/A | Warren County #842564 | Warren | VA | 72+ |
| 18 | Brunswick County | Transcontinental Gas Pipe Line Company, LLC | N/A | Brunswick County #9008686 | Brunswick | VA | 6+ |

Exhibit Lander-3 (a)

Iteration 123 - with Maximum Exhibit P Rates and Periodic Rates Cases

## Calculation of Net Cost to DOM VA Ratepayers using Basis Iteration 123 in IRP Model and Maximum Exhibit P ACP Rates

VPSE rate Pd to ACP "Price Spread": $ 1.75

Subscription in ACP (Dthd): 300,000

Portion of Rate pd that is Return: 75%

| Iteration | Year | AvgOf DomSP | AvgOf TranscoZ5 | Value of ACP ($/Dthd) | Cost of ACP ($/Dthd) | Net Cost of ACP/Dthd | 300,000 | Annual Contract Cost to Ratepayers 1/ | Value of return to DOM Assumes 5 year Rate Cases | |
|---|---|---|---|---|---|---|---|---|---|---|
| 123 | 2017 | ($1.21) | $0.70 | $1.91 | | | | | | |
| 123 | 2018 | ($0.81) | $0.26 | $1.07 | | | | | | |
| 123 | 2019 | ($0.58) | $0.09 | $0.67 | $1.75 | $1.08 | $118,314,392 | $191,625,000 | $143,718,750 | |
| 123 | 2020 | ($0.44) | $0.45 | $0.89 | $1.75 | $0.86 | $93,830,897 | $191,625,000 | $143,718,750 | |
| 123 | 2021 | ($0.79) | $0.11 | $0.90 | $1.75 | $0.85 | $93,053,987 | $191,625,000 | $143,718,750 | |
| 123 | 2022 | ($0.75) | ($0.10) | $0.65 | $1.75 | $1.10 | $120,105,456 | $191,625,000 | $143,718,750 | |
| 123 | 2023 | ($0.71) | ($0.33) | $0.38 | $1.75 | $1.37 | $150,329,909 | $191,625,000 | $143,718,750 | |
| 123 | 2024 | ($0.73) | ($0.52) | $0.21 | $1.58 | $1.37 | $149,538,122 | $172,462,500 | $129,346,875 | |
| 123 | 2025 | ($0.82) | ($0.36) | $0.46 | $1.58 | $1.12 | $122,490,566 | $172,462,500 | $129,346,875 | |
| 123 | 2026 | ($0.73) | ($0.32) | $0.40 | $1.58 | $1.17 | $128,179,693 | $172,462,500 | $129,346,875 | |
| 123 | 2027 | ($0.88) | ($0.60) | $0.28 | $1.58 | $1.30 | $142,310,712 | $172,462,500 | $129,346,875 | |
| 123 | 2028 | ($0.86) | ($0.38) | $0.48 | $1.58 | $1.09 | $119,509,190 | $172,462,500 | $129,346,875 | |
| 123 | 2029 | ($0.79) | ($0.73) | $0.06 | $1.42 | $1.36 | $148,681,352 | $155,216,250 | $116,412,188 | |
| 123 | 2030 | ($0.78) | ($0.49) | $0.29 | $1.42 | $1.12 | $123,154,453 | $155,216,250 | $116,412,188 | |
| 123 | 2031 | ($0.75) | ($0.43) | $0.33 | $1.42 | $1.09 | $119,288,293 | $155,216,250 | $116,412,188 | |
| 123 | 2032 | ($0.78) | ($0.06) | $0.72 | $1.42 | $0.70 | $76,238,817 | $155,216,250 | $116,412,188 | |
| 123 | 2033 | ($0.77) | ($0.25) | $0.52 | $1.42 | $0.90 | $98,396,684 | $155,216,250 | $116,412,188 | |
| 123 | 2034 | ($0.69) | ($0.35) | $0.35 | $1.28 | $0.93 | $101,492,900 | $139,694,625 | $104,770,969 | |
| 123 | 2035 | ($0.73) | ($0.30) | $0.43 | $1.28 | $0.85 | $92,798,360 | $139,694,625 | $104,770,969 | |
| 123 | 2036 | ($0.69) | ($0.38) | $0.31 | $1.28 | $0.97 | $105,747,743 | $139,694,625 | $104,770,969 | |
| 123 | 2037 | ($0.69) | ($0.18) | $0.51 | $1.28 | $0.76 | $83,367,643 | $139,694,625 | $104,770,969 | |
| 123 | 2038 | ($0.85) | ($0.49) | $0.35 | $1.28 | $0.92 | $100,856,165 | $139,694,625 | $104,770,969 | |
| 123 | 2039 | ($0.73) | ($0.47) | $0.25 | | | | | | |
| 123 | 2040 | ($0.80) | ($0.30) | $0.49 | | | | | | |
| 123 | 2041 | ($0.79) | ($0.53) | $0.26 | | | | | | |
| 123 | 2042 | ($0.76) | ($0.70) | $0.06 | | | | | | |
| | Over 20 Years of ACP | ($0.74) | ($0.28) | $0.46 | $1.50 | $1.04 | $2,287,685,333 | $3,294,991,875 | $2,471,243,906 | $183,558,573 |
| | | | | Avg Delta to DOM SP | Avg 20Year levelized cost | Avg 20 Net Cost of ACP | Net Cost of ACP to Ratepayers over 20 Year Contract | Total Rate Payer Cost | Total value of return on 300,000 Dthd of Capacity | Est'd Return Left over after Ratepayer Keep Whole |

Exhibit Lander-3 (b)

Iteration 123 - with Typical Foundation Shipper Rates and Periodic Rates Cases

# Calculation of Net Cost to DOM VA Ratepayers using Basis Iteration 123 in IRP Model and Estimated Foundation Shipper ACP Rates

VPSE rate Pd to ACP $ 1.40

| Iteration | Year | AvgOf DomSP | AvgOf TranscoZ5 | "Price Spread" Value of ACP ($/Dthd) | Cost of ACP ($/Dthd) | Net Cost of ACP/Dthd | Subscription in ACP (Dthd) 300,000 | Annual Contract Cost to Ratepayers 1/ | Value of return to DOM Assumes 5 year Rate Cases | |
|---|---|---|---|---|---|---|---|---|---|---|
| 123 | 2017 | ($1.21) | $0.70 | $1.91 | | | | | | |
| 123 | 2018 | ($0.81) | $0.26 | $1.07 | | | | | | |
| 123 | 2019 | ($0.58) | $0.09 | $0.67 | $1.40 | $0.73 | $79,989,392 | $153,300,000 | $105,393,750 | |
| 123 | 2020 | ($0.44) | $0.45 | $0.89 | $1.40 | $0.51 | $55,505,897 | $153,300,000 | $105,393,750 | |
| 123 | 2021 | ($0.79) | $0.11 | $0.90 | $1.40 | $0.50 | $54,728,987 | $153,300,000 | $105,393,750 | |
| 123 | 2022 | ($0.75) | ($0.10) | $0.65 | $1.40 | $0.75 | $81,780,456 | $153,300,000 | $105,393,750 | |
| 123 | 2023 | ($0.71) | ($0.33) | $0.38 | $1.40 | $1.02 | $112,004,909 | $153,300,000 | $105,393,750 | |
| 123 | 2024 | ($0.73) | ($0.52) | $0.21 | $1.26 | $1.05 | $115,045,622 | $137,970,000 | $94,854,375 | |
| 123 | 2025 | ($0.82) | ($0.36) | $0.46 | $1.26 | $0.80 | $87,998,066 | $137,970,000 | $94,854,375 | |
| 123 | 2026 | ($0.73) | ($0.32) | $0.40 | $1.26 | $0.86 | $93,687,193 | $137,970,000 | $94,854,375 | |
| 123 | 2027 | ($0.88) | ($0.60) | $0.28 | $1.26 | $0.98 | $107,818,212 | $137,970,000 | $94,854,375 | |
| 123 | 2028 | ($0.86) | ($0.38) | $0.48 | $1.26 | $0.78 | $85,016,690 | $137,970,000 | $94,854,375 | |
| 123 | 2029 | ($0.79) | ($0.73) | $0.06 | $1.13 | $1.07 | $117,638,102 | $124,173,000 | $85,368,938 | |
| 123 | 2030 | ($0.78) | ($0.49) | $0.29 | $1.13 | $0.84 | $92,111,203 | $124,173,000 | $85,368,938 | |
| 123 | 2031 | ($0.75) | ($0.43) | $0.33 | $1.13 | $0.81 | $88,245,043 | $124,173,000 | $85,368,938 | |
| 123 | 2032 | ($0.78) | ($0.06) | $0.72 | $1.13 | $0.41 | $45,195,567 | $124,173,000 | $85,368,938 | |
| 123 | 2033 | ($0.77) | ($0.25) | $0.52 | $1.13 | $0.62 | $67,353,434 | $124,173,000 | $85,368,938 | |
| 123 | 2034 | ($0.69) | ($0.35) | $0.35 | $1.02 | $0.67 | $73,553,975 | $111,755,700 | $76,832,044 | |
| 123 | 2035 | ($0.73) | ($0.30) | $0.43 | $1.02 | $0.59 | $64,859,435 | $111,755,700 | $76,832,044 | |
| 123 | 2036 | ($0.69) | ($0.38) | $0.31 | $1.02 | $0.71 | $77,808,818 | $111,755,700 | $76,832,044 | |
| 123 | 2037 | ($0.69) | ($0.18) | $0.51 | $1.02 | $0.51 | $55,428,718 | $111,755,700 | $76,832,044 | |
| 123 | 2038 | ($0.85) | ($0.49) | $0.35 | $1.02 | $0.67 | $72,917,240 | $111,755,700 | $76,832,044 | |
| 123 | 2039 | ($0.73) | ($0.47) | $0.25 | | | | | | |
| 123 | 2040 | ($0.80) | ($0.30) | $0.49 | | | | | | |
| 123 | 2041 | ($0.79) | ($0.53) | $0.26 | | | | | | |
| 123 | 2042 | ($0.76) | ($0.70) | $0.06 | | | | | | |
| Over 20 Years of ACP | | ($0.74) | ($0.28) | $0.46 | $1.20 | $0.74 | $1,628,686,958 | $2,635,993,500 | $1,812,245,531 | $183,558,573 |
| | | | | Avg Delta to DOM SP | Avg 20Year levelized cost | Avg 20 Net Cost of ACP | Net Cost of ACP to Ratepayers over 20 Year Contract | Total Rate Payer Cost | Total value of return on 300,000 Dthd of Capacity | Est'd Return Left over after Ratepayer Keep Whole |

Exhibit Lander-3 (c)

Average of All 200 Iterations with Maximum Exhibit P Rates and Periodic Rates Cases

## Calculation of Net Cost to DOM VA Ratepayers using of 200 Basis Iterations in IRP Model and Maximum Exhibit P ACP Rates

VPSE rate Pd to ACP $ 1.75

Portion of Rate pd that is Return 75%

| Year | AvgOf AvgOf DomSP | AvgOf AvgOf TranscoZ5 | "Price Spread" Value of ACP | Cost of ACP | Net Cost of ACP | Subscription in ACP (Dthd) 300,000 | Annual Contract Cost to Ratepayers | Value of return to DOM | |
|---|---|---|---|---|---|---|---|---|---|
| 2017 | ($1.14) | $0.64 | $1.78 | | | | | | |
| 2018 | ($0.74) | $0.60 | $1.34 | | | | | | |
| 2019 | ($0.52) | $0.35 | $0.87 | $1.75 | $0.88 | $96,772,448 | $191,625,000 | $143,718,750 | |
| 2020 | ($0.55) | $0.00 | $0.56 | $1.75 | $1.19 | $130,620,350 | $191,625,000 | $143,718,750 | |
| 2021 | ($0.64) | ($0.10) | $0.54 | $1.75 | $1.21 | $132,399,471 | $191,625,000 | $143,718,750 | |
| 2022 | ($0.69) | ($0.19) | $0.50 | $1.75 | $1.25 | $137,044,641 | $191,625,000 | $143,718,750 | |
| 2023 | ($0.77) | ($0.36) | $0.41 | $1.75 | $1.34 | $146,617,682 | $191,625,000 | $143,718,750 | |
| 2024 | ($0.75) | ($0.37) | $0.37 | $1.58 | $1.20 | $131,477,833 | $172,462,500 | $129,346,875 | |
| 2025 | ($0.76) | ($0.39) | $0.37 | $1.58 | $1.21 | $132,201,601 | $172,462,500 | $129,346,875 | |
| 2026 | ($0.75) | ($0.38) | $0.38 | $1.58 | $1.20 | $131,309,524 | $172,462,500 | $129,346,875 | |
| 2027 | ($0.82) | ($0.48) | $0.34 | $1.58 | $1.24 | $135,471,671 | $172,462,500 | $129,346,875 | |
| 2028 | ($0.84) | ($0.48) | $0.36 | $1.58 | $1.21 | $132,941,240 | $172,462,500 | $129,346,875 | |
| 2029 | ($0.81) | ($0.42) | $0.39 | $1.42 | $1.03 | $112,406,284 | $155,216,250 | $116,412,188 | |
| 2030 | ($0.79) | ($0.40) | $0.39 | $1.42 | $1.03 | $112,613,476 | $155,216,250 | $116,412,188 | |
| 2031 | ($0.76) | ($0.36) | $0.40 | $1.42 | $1.02 | $111,866,887 | $155,216,250 | $116,412,188 | |
| 2032 | ($0.75) | ($0.33) | $0.42 | $1.42 | $1.00 | $109,471,659 | $155,216,250 | $116,412,188 | |
| 2033 | ($0.73) | ($0.32) | $0.41 | $1.42 | $1.01 | $110,153,626 | $155,216,250 | $116,412,188 | |
| 2034 | ($0.72) | ($0.26) | $0.46 | $1.28 | $0.82 | $89,467,973 | $139,694,625 | $104,770,969 | |
| 2035 | ($0.71) | ($0.26) | $0.44 | $1.28 | $0.83 | $91,148,310 | $139,694,625 | $104,770,969 | |
| 2036 | ($0.72) | ($0.29) | $0.44 | $1.28 | $0.84 | $92,002,722 | $139,694,625 | $104,770,969 | |
| 2037 | ($0.73) | ($0.30) | $0.43 | $1.28 | $0.84 | $92,262,820 | $139,694,625 | $104,770,969 | |
| 2038 | ($0.73) | ($0.29) | $0.44 | $1.28 | $0.84 | $91,720,577 | $139,694,625 | $104,770,969 | |
| 2039 | ($0.73) | ($0.28) | $0.45 | | | | | | |
| 2040 | ($0.73) | ($0.30) | $0.43 | | | | | | |
| 2041 | ($0.73) | ($0.30) | $0.44 | | | | | | |
| 2042 | ($0.72) | ($0.31) | $0.42 | | | | | | |
| Over 20 Years of ACP | ($0.73) | ($0.28) | $0.45 | $1.50 | $1.06 | $2,319,970,794 | $3,294,991,875 | $2,471,243,906 | $151,273,112 |
| | | | Avg Delta to DOM SP | Avg 20Year levelized cost | Avg 20 Net Cost of ACP | Net Cost of ACP to Ratepayers over 20 Year Contract | Total Rate Payer Cost | Total value of return on 300,000 Dthd of Capacity | Est'd Return Left over after Ratepayer Keep Whole |

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Exhibit Lander-3 (d)

Average of All 200 Iterations - with Typical Foundation Shipper Rates and Periodic Rates Cases

## Calculation of Net Cost to DOM VA Ratepayers using Average of 200 Basis Iterations in IRP Model and Estimated Foundation Shipper ACP Rates

| Year | | AvgOf AvgOf DomSP | AvgOf AvgOf TranscoZ5 | VPSE rate Pd to ACP "Price Spread" Value of ACP | $ 1.40 Cost of ACP | Net Cost of ACP | Subscription in ACP (Dthd) 300,000 | Annual Contract Cost to Ratepayers | Value of return to DOM | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2017 | ($1.14) | $0.64 | $1.78 | | | | | | |
| | 2018 | ($0.74) | $0.60 | $1.34 | | | | | | |
| | 2019 | ($0.52) | $0.35 | $0.87 | $1.40 | $0.53 | $58,447,448 | $153,300,000 | $105,393,750 | |
| | 2020 | ($0.55) | $0.00 | $0.56 | $1.40 | $0.84 | $92,295,350 | $153,300,000 | $105,393,750 | |
| | 2021 | ($0.64) | ($0.10) | $0.54 | $1.40 | $0.86 | $94,074,471 | $153,300,000 | $105,393,750 | |
| | 2022 | ($0.69) | ($0.19) | $0.50 | $1.40 | $0.90 | $98,719,641 | $153,300,000 | $105,393,750 | |
| | 2023 | ($0.77) | ($0.36) | $0.41 | $1.40 | $0.99 | $108,292,682 | $153,300,000 | $105,393,750 | |
| | 2024 | ($0.75) | ($0.37) | $0.37 | $1.26 | $0.89 | $96,985,333 | $137,970,000 | $94,854,375 | |
| | 2025 | ($0.76) | ($0.39) | $0.37 | $1.26 | $0.89 | $97,709,101 | $137,970,000 | $94,854,375 | |
| | 2026 | ($0.75) | ($0.38) | $0.38 | $1.26 | $0.88 | $96,817,024 | $137,970,000 | $94,854,375 | |
| | 2027 | ($0.82) | ($0.48) | $0.34 | $1.26 | $0.92 | $100,979,171 | $137,970,000 | $94,854,375 | |
| | 2028 | ($0.84) | ($0.48) | $0.36 | $1.26 | $0.90 | $98,448,740 | $137,970,000 | $94,854,375 | |
| | 2029 | ($0.81) | ($0.42) | $0.39 | $1.13 | $0.74 | $81,363,034 | $124,173,000 | $85,368,938 | |
| | 2030 | ($0.79) | ($0.40) | $0.39 | $1.13 | $0.74 | $81,570,226 | $124,173,000 | $85,368,938 | |
| | 2031 | ($0.76) | ($0.36) | $0.40 | $1.13 | $0.74 | $80,823,637 | $124,173,000 | $85,368,938 | |
| | 2032 | ($0.75) | ($0.33) | $0.42 | $1.13 | $0.72 | $78,428,409 | $124,173,000 | $85,368,938 | |
| | 2033 | ($0.73) | ($0.32) | $0.41 | $1.13 | $0.72 | $79,110,376 | $124,173,000 | $85,368,938 | |
| | 2034 | ($0.72) | ($0.26) | $0.46 | $1.02 | $0.56 | $61,529,048 | $111,755,700 | $76,832,044 | |
| | 2035 | ($0.71) | ($0.26) | $0.44 | $1.02 | $0.58 | $63,209,385 | $111,755,700 | $76,832,044 | |
| | 2036 | ($0.72) | ($0.29) | $0.44 | $1.02 | $0.59 | $64,063,797 | $111,755,700 | $76,832,044 | |
| | 2037 | ($0.73) | ($0.30) | $0.43 | $1.02 | $0.59 | $64,323,895 | $111,755,700 | $76,832,044 | |
| | 2038 | ($0.73) | ($0.29) | $0.44 | $1.02 | $0.58 | $63,781,652 | $111,755,700 | $76,832,044 | |
| | 2039 | ($0.73) | ($0.28) | $0.45 | | | | | | |
| | 2040 | ($0.73) | ($0.30) | $0.43 | | | | | | |
| | 2041 | ($0.73) | ($0.30) | $0.44 | | | | | | |
| | 2042 | ($0.72) | ($0.31) | $0.42 | | | | | | |
| Over 20 Years of ACP | | ($0.73) | ($0.28) | $0.45 | $1.20 | $0.76 | $1,660,972,419 | $2,635,993,500 | $1,812,245,531 | $151,273,112 |
| | | | | Avg Delta to DOM SP | Avg 20Year levelized cost | Avg 20 Net Cost of ACP | Net Cost of ACP to Ratepayers over 20 Year Contract | Total Rate Payer Cost | Total value of return on 300,000 Dthd of Capacity | Est'd Return Left over after Ratepayer Keep Whole |